1999 Electricity Generation Emissions Report

A REPORT TO THE LEGISLATURE

as directed by SB 1305 (Statutes of 1997)

STATE OF CALIFORNIA
ENERGY COMMISSION

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ENERGY
COMMISSION

Gray Davis, *Governor*

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Ross Miller, *Project Manager*
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ELECTRICITY ANALYSIS OFFICE

H. Dan Nix, *Deputy Director*

ENERGY INFORMATION & ANALYSIS DIVISION

Acknowledgements

California Energy Commission Staff

Matthew Layton, Principal Author
Energy Facilities Siting & Environmental Division

Ross Miller, Project Manager
Lynn Marshall, Emission Reduction Incentives
Energy Information & Analysis Division

Nan Powers, Global Climate Change
Energy Technology Development Division

Kent Smith, Acting Executive Director

Daniel Nix, Deputy Director
Energy Information & Analysis Division
Bob Therkelsen, Deputy Director
Energy Facilities Siting & Environmental Protection Division

The following staff of the California Air Resources Board and affected local air districts provided valuable assistance to Energy Commission staff in the preparation of this report:

Robert Fletcher	Chief, Emissions Assessment Branch Stationary Sources Division California Air Resource Board
Larry Allen	San Luis Obispo Air Pollution Control District
Janet Brennan	Monterey Bay Unified Air Pollution Control District
Elaine Chang	South Coast Air Quality Management District
Michael Kussow	Shasta County Air Quality Management District
Ken Lim	Bay Area Air Quality Management District
Joan Merchen	San Joaquin Valley Air Pollution Control District
Robert Reynolds	Lake County Air Pollution Control District
Robert Zeller	Mojave Desert Air Pollution Management District

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Executive Summary

Senate Bill 1305 (Chapter 796, Statutes of 1997) directed the Energy Commission, in conjunction with the California Air Resources Board and affected air districts, to issue a report to the Legislature assessing effects on the air emissions of electric utility restructuring. By mandating this report, the Legislature implicitly raised the concern whether the existing air quality management plans, regulations and permitting processes are robust with respect to such changes.

This report reviews the activities of the past two years related to electricity industry restructuring and generation emissions and describes future activities which are important to ensuring continued effective management of electricity generation emissions. This report finds that air quality regulators can use the existing air quality regulatory framework to respond to ongoing and proposed structural and regulatory changes in the electricity industry. Current and future air quality permitting, rulemaking, and planning activities within that framework should take into account the changes occurring within the electricity industry to ensure emissions reductions are achieved as efficiently as practicable.

Despite continued growth of the state's population and economy, air quality is improving throughout California. Air districts with the most severe problems, however, do not expect to attain the ambient air quality standards until late in the next decade. For air quality managers, reducing emissions from electricity generation is a key element in their efforts to achieve and maintain the standards. Patterns of electricity generation will likely change in the future in response to a combination of factors including growing demand, replacement or refurbishment of aging power plants, technological innovations for new power plants, economic pressures, and specific features of electricity industry structural and regulatory changes.

Existing air quality management strategies could be affected by ongoing structural and regulatory changes in the electricity industry. To ensure that air quality programs continue to be successful, all concerned agencies—the Energy Commission, California Air Resources Board, affected air districts, and U.S. Environmental Protection Agency—should continue their efforts to coordinate air quality management strategies with changes in the electricity industry, as in the following:

- Continued regular meetings among the staff of these agencies.

- Continued coordination should help the California Air Resources Board implement their *Guidance Document for Major Power Plants Permits*, future California Air Resources Board and district rules changes, or future air quality management plan updates.

- Continued coordination should facilitate the U.S. Environmental Protection Agency's timely participation in the licensing process to assure timely review and consistency between State and federal permits.

Air quality regulators are responding within the existing regulatory framework to ensure that electricity industry restructuring will not, by itself, result in a deterioration of air quality from increases in emissions from electricity generation.

- Air districts have adopted rules requiring best available retrofit control technologies for existing power plants.

- Electricity generation facilities are required to comply with the retrofit regulations, in most cases, by early in the next decade, and these regulations will be a key component of most district air quality maintenance strategies.

- Current attainment plans include rules and regulations that require existing boilers to operate at emission levels that are some of the lowest in the country.

- The California Public Utilities Commission's environmental review of thermal power plant divestiture concluded that no significant unavoidable environmental impacts are likely to result from the action.
    - The resulting environmental impact reports or negative declarations have confirmed that no significant air quality impacts would result from the change in ownership of existing generation, with the implementation of some mitigation measures.

- The districts already have revised, or currently plan or do not need to revise their best available retrofit control technology rules to ensure that they continue to effectively regulate existing power plants, regardless of divestiture.
    - Some changes in district rules are required as mitigation for divestiture (for example, altering rules to apply to non-utility owners of the facilities formerly owned by utilities).

    - Regardless of the implications of restructuring on the operating patterns of most generators in the South Coast District, the RECLAIM program should result in no net change in oxides of nitrogen emissions. If higher demand for RECLAIM Trading Credits results in higher RECLAIM Trading Credits prices, some generation could shift to other air basins if the RECLAIM Trading Credits costs are higher than other variable costs.

The Energy Commission expects to review licensing proposals for as many as 30 large central station power plant projects in next two to four years. One such project has already been licensed, and 19 others have already begun or are scheduled to begin the licensing process.

- All are subject to New Source Review requirements (which ensure no significant deterioration of air quality will result) and will also use the best available emission control technology. Most, if not all, of the proposed projects will be required to secure emission offsets to prevent a significant deterioration in air quality.

- Recognizing the need for consistency in permitting, the California Air Resources Board is already preparing a *Guidance Document for Major Power Plant Permits* to provide districts with specific guidance for emission control requirements and emission offsets, including interdistrict and interpollutant offsets.

- Where offsets are scarce, expanding the potential sources and uses of emission reduction credits can ease shortages and facilitate environmentally appropriate economic growth, benefiting air quality programs as well as generation markets.
    - The districts should continue their efforts to expand the use of incentive-based emission reduction programs to increase the availability of Emission Reduction Credits needed to meet offset requirements. For example, the South Coast Air Quality Management District's Area Source Credit Rule encourages new emission reductions by establishing a procedure for quantifying real, surplus, verifiable emission reductions from area sources.

    - Including a broader array of emission reduction sources (than a generation-only approach) can result in lower costs, lower emissions and spur emission-reducing innovations in all sectors of the economy.

When updating their air quality plans, the air districts need to ensure that the assumptions in their plans' expected source category emission reductions and regulatory strategies (rule changes) are taking current and potential electricity industry changes into account.

- Restructuring and divestiture may lead to different economic incentives to run, retrofit, refurbish, repower, replace or retire existing power plants than assumed in current plans.

- Air quality managers need to understand and take into account the inherent uncertainty that will continue to exist during the restructuring transition period and perhaps beyond regarding:
    - future market penetration of distributed energy resources and their emission characteristics and
    - the magnitude and duration of public purpose funding for renewable generation, demand-side management, and emissions-related research and development.

Introduction

This report, the ***1999 Electricity Generation Emissions Report (EGER)***, responds to the legislative mandate in Senate Bill 1305 [Public Utilities Code, Division 1, Part 1, Chapter 2.3, Section 398.5(h).] When the California State Legislature enacted SB 1305 in late 1997, it acknowledged the possibility that air emissions from electricity generation could be affected by structural and regulatory changes in the electricity industry. SB 1305 directed the Energy Commission, in conjunction with the California Air Resources Board and affected air districts, to issue a report to the Legislature assessing effect on air emission of electric utility restructuring. Individuals interested in the implications of restructuring on generation emissions and air quality regulations should read this report. This report does not, however, attempt to predict potential changes to California air quality.

Why Be Concerned If Patterns of Generation Change?

Air quality throughout California is improving, despite continued growth of the State's population and economy. But attainment of ambient air quality standards in the air districts with the most severe air quality problems is not projected until late in the next decade. Air pollutant emissions (emissions) from electricity generation are among the key emissions that air quality managers regulate to achieve and maintain healthful air quality. As measured by annual average tons per day, power plant emissions account for less than one percent of the statewide total of reactive organic gases (ROG), carbon monoxide (CO) and particulate matter under ten microns (PM10); less than three percent of oxides of nitrogen (NO_X); and less than five percent of sulfur (SO_X). In some districts, however, power plant emissions are a significant portion of the emissions inventory. Regardless of the relative contribution to total emissions, power plant emissions ought to be kept as low as economically justified.

How is California's Electricity Market Changing?

Patterns of electricity generation will change in the future in response to changing demand, replacement of aging power plants, technological innovations for new power plants, economic pressures, and electricity industry structural and regulatory changes. As listed below, certain aspects of the current and future electricity market, which are to varying degrees linked to specific features of California industry restructuring, do have the potential to change patterns of generation and generation emissions. For the reader unfamiliar with details of some of these features of restructuring, Appendices A and B provide some additional description and history of restructuring and divestiture. These features include the following:

- Expectations of low fall, winter and spring electricity prices but very high summer prices.

- The divestiture of most of the existing investor-owned utility fossil power plants, their purchase by nonutility entities often new to California, and the operation of these power plants within a competitive electricity market.

- The proposed construction, on the near-term licensing horizon, of almost thirty new gas-fired merchant power plants, although the number of projects that ultimately will be constructed is highly uncertain.

- The near-term buy-down of utility stranded assets, including nuclear, that may increase the likelihood of operating changes (e.g., retirement, refurbishment, replacement) of existing units, thereby contributing to changes in patterns of generation.

- When generation-related stranded costs are paid off, electricity prices are expected to decrease. This price decrease could lead to an increase in electricity demand which could lead to higher generation emissions than expected in air quality management plans.

- The collection from ratepayers of direct “public purpose program” surcharges for promoting renewable generation (including wind, geothermal, landfill gas, small hydroelectric, and biomass), demand-side management, and electricity-related research.

- The differentiation of retail electricity products through mandated “fuel content” labeling (e.g., distinguishing renewable electricity generation from coal generation).

- The potential deployment of distributed energy generating resources.

- New mechanisms to manage the constraints imposed by electricity transmission system congestion and reliability requirements.

The following factors, although not directly related to California electric industry restructuring, may also have an effect on in-state generation and air pollutant emissions:

- Implementation of the acid rain and sulfur dioxide trading program, which mostly affect out-of-state generation because of the higher sulfur content of coal compared to natural gas.

- Potential global climate change emission reduction initiatives.

Chapter 1

California Ambient Air Pollutant Inventories

The California Air Resources Board, in conjunction with local air districts, monitors air pollutant emission inventories and ambient air quality throughout the state. The most recent published compilation, *The 1999 California Almanac of Emissions and Air Quality*, provides emission inventories and air quality data for 1995 and before. Emission inventories for 1996 are available from the Air Resources Board Web Site section named *California Emissions Inventory Data*. While these emission inventories and air quality data are for years before restructuring, they do show the relative contribution of electricity generation emissions to overall emission inventories and air quality trends.

Measured by annual average tons per day, power plant emissions of ROG, CO and PM10 account for less than one percent of the statewide total, less than three percent of statewide NO_X, and less than five percent of statewide SO_X. In some districts, however, power plant emissions are a significant portion of the emission inventory.

Urban areas continue to have larger emissions inventories and higher ambient air pollutant measurements. This is mostly due to the higher concentrations of industries, motor vehicles and residents. Emissions inventories in an air basin may not correlate directly to air quality. Air quality is a complex function of air pollutant inventories, air pollutant emission rates, air pollutant transport, geography, and meteorology. Attainment strategies attempt to balance these factors, while enacting the most cost-effective control measures across emission sources and business sectors.

Electricity Generating Plant Emissions

Several pollutants are of concern from electricity generation including NO_X, SO_X, ROG, and PM10. **Table 1** shows the air emissions for the state and in-state electricity production for California Best Available Control Retrofit Technology (BARCT) before the existing BARCT rules are implemented, which will dramatically lower NO_X emissions.

Table 1 shows SO_X numbers that are higher than expected for a fossil generation system dominated by natural gas. The 1996 inventories included SO_X emissions from utilities burning down stocks of residual oil in preparation for the phase-out of oil as a back-up fuel; therefore, SO_X emissions from California generation are expected to decrease from 1996 levels. Additionally, the SO_X inventory includes emissions from a minor amount of coal and petroleum coke-fired generation and distillate firing in peaking combustion turbines.

Table 1
1996 Statewide Electricity and Total Air Pollutant Emissions Inventories

Emission Inventory (tons/day, annual average)					
Source Category	**ROG**	**CO**	**NO_x**	**SO_x**	**PM10**
Fuel Combustion	37	270	520	61	42
Subtotal Electric generation	***7***	***71***	***94***	***11***	***9***
utilities	***4***	***33***	***52***	***9***	***5***
cogeneration	***3***	***38***	***42***	***2***	***4***
Other fuel combustion	***30***	***199***	***426***	***50***	***33***
Waste Disposal	21	2	2	1	6
Cleaning & Surface Coating	390	0	0	0	1
Petroleum Production & Marketing	210	8	20	62	4
Industrial Processes	57	70	84	26	88
Total Stationary Sources	**710**	**350**	**630**	**150**	**140**
Area-Wide Sources	**770**	**2,700**	**93**	**5**	**2,000**
Mobile Sources	**1,700**	**15,000**	**2,600**	**97**	**110**
Natural (Non-Anthropogenic) Sources	**53**	**580**	**9**	**0**	**90**
All Sources	**3,200**	**19,000**	**3,300**	**250**	**2,350**

Source: CARB, California Emission Inventory Data, Updated April 26, 1999
www.arbis.arb.ca.gov/emisinv/emsmain

Are Electricity Generation Air Emissions Important?

The fossil-fueled electric generation sector in California is only a small portion of the total emissions inventory.[1] However, power plant emissions are among the largest stationary source category and, in a few air districts, are very significant portions of the total emissions inventory. Therefore, they have been targeted for emission reductions by most non-attainment air districts as part of their attainment plans. Air districts have adopted rules requiring BARCT for existing power plants and best available control technology (BACT) for new power plants. Compliance with the retrofit regulations is required, in most cases, by early in the next decade and will be a key component of most district attainment strategies.

NO_X, as a precursor to ozone, continue to be the primary focus of regulators and power plant operators. The BARCT rules will reduce NO_X emissions from existing power plants by 70 to 90 percent (compared to emissions before BARCT implementation). Emissions of ROG and SO_X from the generation sector are already low due to the almost exclusive use of natural gas as fuel in thermal power plants. Most of the state is in attainment for CO except for parts of South Coast and the border crossing at Calexico. The CO non-attainment areas are dominated by impacts from the mobile sector; thus, the generation sector will play no significant role in attaining the CO standards.

In 1997, the U.S. EPA promulgated a new eight-hour ozone ambient air quality standard and new standards for (PM2.5) and revised a previous standard for PM10. In May 1999, a U.S.

Court of Appeals essentially removed the new PM10 revision, put enforcement of the new ozone standard on hold, and asked for more comments on the new PM2.5 standard. California's state standards, which are at least as health protective as the new federal standards, still apply, however, and most Californians live in areas that still violate the federal and state one-hour ozone standards. Therefore, the CARB will continue to implement existing programs and pursue new emission reduction measures to meet these standards. With respect to the new standards, the districts are collecting data to determine attainment status and will prepare implementation plans to submit to the CARB and U.S. EPA. Until the monitoring systems are implemented to determine attainment status, it is unclear what potential control measures might be proposed for ozone precursors – NO_X and ROG. While California's total and fossil-only electricity generation systems are among the cleanest in the nation, air quality regulators will continue to look to this large stationary source of emissions and precursors for potential emission reductions and technological innovations.

What About Particulate Matter?

Directly emitted PM10 from the electricity generation sector currently appears to be relatively insignificant. However, several changes may result in greater emphasis being placed on particulate emissions from the generation sector in the future. First, greater California reliance on combustion turbines may increase directly emitted PM10 from the generation sector. It appears that the NO_X controls employed on modern combustion turbines reduce firing temperatures so that particulate emissions are greater than from boilers.

Second, the U.S. EPA recently adopted standards for PM2.5 in addition to the PM10 standards. PM2.5 consists of directly emitted particulate matter, and secondary particulate matter, such as nitrates, sulfates, and condensables that are formed in the atmosphere from precursors such as NO_X, ammonia, $SO_{X,}$ and complex hydrocarbons. Because PM2.5 is a subset of PM10, these precursors contribute to PM10 pollution as well. The control of the particulate precursors from generation will be part of the PM10 and PM2.5 attainment plans.

As described above, the recent court decision also affects the PM standards. However, the U.S. EPA set the implementation schedule for the PM2.5 standards on a time line to allow the agency to complete its next review of the PM standards in 2002 before designating nonattainment areas and requiring implementation plans for PM2.5. With this lengthy time line, the CARB expects the legal challenges and uncertainty regarding the PM2.5 standards to be resolved without delaying future implementation of the standards. In the meanwhile, PM10 nonattainment areas will continue to implement their plans to attain the existing PM10 standards.

Emissions factors for the fine particles emitted directly by stationary sources are largely unavailable. Districts are collecting data to determine attainment status and will prepare implementation plans for submittal to the CARB and U.S. EPA. The data will be collected throughout the next few years with determination of attainment status and development of attainment strategies and plans to follow a few years later. Any comprehensive system for regulating PM2.5 must take into account not only the fine particles emitted directly by stationary sources but also the various precursors (*e.g.*, combustion byproducts) which result in secondarily-formed fine particles through chemical reactions in the atmosphere. Secondary PM may account for over half of total ambient PM2.5 nationwide.

The BACT for controlling PM emissions from electric generation is defined as the emission rate that results from burning natural gas with fuel sulfur content of no more than 1 grain/100 standard cubic foot. Since this is the fuel of choice for most proposed power plants in California, the main implication of the small particulate standards for new generation would be on the amount of offsets require. Offsets are currently required for PM10 emissions. Whether they will be required for PM2.5 emissions depends on the outcome of the current court case.

Endnotes

1. As an example, NO_X from electricity generation are about four percent of the total statewide annual inventory of NO_X. In comparison, electricity generation contributes as much as 35 percent of the NO_X annual inventory of San Luis Obispo County, and nationwide contributes approximately 33 percent of the national NO_X inventory. The differences are due to the number of sources in any one air district, the significant use of coal for power generation outside of California and the degree to which California generation has already installed emission controls and uses natural gas.

Chapter 2

Implications of Restructuring on Regulated Emissions of Existing Generation

Environmental Reviews of Divestiture

Since SB 1305 was enacted, the California Public Utilities Commission has conducted environmental reviews, including a review of potential impacts of possible generation emissions changes that may result from the divestiture of the gas-fired power plants owned by investor-owned utilities. The resulting environmental impact reports or negative declarations have confirmed that no significant air quality impacts would result from the change in ownership of existing generation, with the implementation of some mitigation measures. For example, the environmental review found that many district air quality regulations pertaining to electricity generation applied only to facilities owned and operated by regulated utilities. Many districts have since modified their regulations so that they apply to a facility regardless of ownership. **Table 2** describes the recent actions taken by districts to rectify this problem.

Why Are BARCT Rules Important?

The methods used by districts to manage future air pollutant emissions vary with attainment status and emissions inventories. Generally, districts estimate future emissions from each source category in the inventory by applying a control factor, *e.g.,* BARCT requirements, and a growth factor, to represent emission increases, to historical emission rates. The operation of each individual power plant is limited by its permit-to-operate, which establishes a maximum emission rate or concentration. Power plants do not run all the time and generally emit fewer pollutants than their permitted levels. Thus, the effective historical emission rate assumed for a power plant in each district's plan is typically less than the maximum permitted rate for that plant. If the power plant runs more than expected (that is, more than it was assumed to run in the planning inventories) then it can be said that its emissions have increased compared to what was counted on in the attainment plan. Potentially, a change in the attainment plan could be needed to ensure maintaining progress to attainment when updating the air quality management plans. The change in the plan may or may not occur in the generation sector.

Table 2
Air District Rules Applicable to Utility Boilers

Bay Area AQMD: Under the current retrofit Regulation 9 Rule 11, divested utility boilers will fall outside of the requirements of the rule. The district is planning to revise the rule in 1999 to address the divestiture of Hunters Point 2 - 4, Potrero Unit 3, Pittsburg Units 1 – 7, and Contra Costa Units 1 - 4. Hunters Point 2-4 is to be closed as soon as possible, per an agreement between PG&E and the City and County of San Francisco.
Monterey Bay Unified APCD: Divested utility boilers would have fallen outside of the requirements of BARCT Rule 431. The District revised the rule in December 1997 to apply to Moss Landing Units 6 & 7.
San Luis Obispo County APCD: Divested utility boilers would have fallen outside of the requirements of BARCT Rule 429. The District revised rule in December 1997 to apply to Morro Bay Units 1-4.
Ventura County APCD: Divested utility boilers would have fallen outside of the requirements of BARCT Rule 59. The District revised the rule in July 1997 so such that the rule applies to Ormond Beach Units 1 & 2 and Mandalay Units 1 & 2.
South Coast AQMD: Under Regulation XX: RECLAIM, facilities, including some power plants, have an annual emissions allocation. Facility compliance with the allocation can be through emission controls, emission credit trading, or process modification or curtailment. Power plants not covered by RECLAIM are subject to Rule 1135, which has daily and annual emission caps.
Mojave Desert AQMD: Retrofit Rule 1158 has an annual emission cap for the Coolwater Units 1 – 4 and includes language for successor owners.
San Diego County APCD: Retrofit Rule 69 has an annual emission cap for utility owned boilers. The rule requires adjustment of the cap if units are sold and specifies the control levels for the sold units. The rule applies to South Bay Units1 - 4 and Encina Units 1- 5.

The BARCT rules are an important part of actions the districts have taken or are taking to manage emission inventories from existing generation sources that may be affected by divestiture. The districts that have anticipated the continued operation of existing generation have or are formulating BARCT rules or market-based rules such as RECLAIM[1] in the South Coast Air Quality Management District. Some air districts needed to change their BARCT regulations to accommodate changes in power plant ownership, as previously explained (See **Table 2**). Regulations containing system-wide emission rates or emission caps have been or can be amended to revert to unit-by-unit emission limitations or be applied proportionally to the remaining system(s).[2] Alternatively, existing generation facilities can be repowered or replaced, with the new technologies being subject to BACT and offset requirements[3] or to RECLAIM. If the units are retired, any emission reductions can be banked, subject to emission reduction credit (ERC) rules or to RECLAIM. (See Appendix C for a description of air emissions implications of the "Five R's"—run, retrofit, repower, replace or retire.)

In the South Coast District, if NO_X emissions increase above the facility's allocation under RECLAIM, these increases must be offset through purchases of RECLAIM Trading Credits (RTCs) from other sources, through process and equipment modifications at the facility itself, or by reducing generation at the facility. Likewise, any emission decrease caused by changes in generating patterns due to restructuring would allow a facility to sell more RTCs to other RECLAIM emission sources. Consequently, regardless of the implications of restructuring on the operating patterns of most generators in the South Coast District, the RECLAIM program should result in no net change in NO_X emissions. If higher demand for RTCs results in higher RTC prices, some generation could shift to other air basins if the RTC costs are higher than other variable costs.

Out-of-State Existing Generation

Depending on the availability of hydroelectric power, California imports between fifteen and twenty-five percent of its electricity from the Pacific Northwest and Desert Southwest. Prevailing winds and geography prevent most out-of-state generation emissions from causing impacts in California. Only in some rare instances can power plants located near the California border have some localized effects in California, including visibility impacts. Therefore, if out-of-state resources provide electricity to California, the impacts on California's air emissions will be minimal. It is also unlikely that the emissions from additional electricity exports to California will have a significant effect on California air emissions.

The development of a robust regional electricity market could increase out-of-state generation and electricity imports to California. It is too early in the evolution of the western electricity market to determine if regional generation patterns will change. However, since most hydroelectric potential in the West has been developed, new out-of- state power plants are likely to be fueled by natural gas or coal. Emissions from out-of-state fossil-fired power plants are regulated by federal rules[4] such as those adopted to limit acid rain and potential visibility impairment on the Colorado Plateau. California needs to follow the continuing evaluation of western regional air quality and emissions by inter-state organizations like the Western Regional Air Partnership. The resulting implementation of control measures on out-of-state generation may affect the availability of electricity for California, thereby affecting California generation patterns. For example, if federal initiatives designed to reduce greenhouse gas emissions are enacted, the economics of coal generation could be seriously and adversely impacted.

Endnotes

1. The RECLAIM is a market incentive program designed to allow facilities flexibility in achieving emission reduction requirements for NO_X and SO_X. The program allows facilities to use methods

not limited to add-on controls, modifications, reformulated products, operational changes, shutdowns, and the purchase of excess emission reductions (RECLAIM Trading Credits - RTCs) to achieve their annual emission allocation. The emission allocations are adjusted down over time to achieve an improvement in ambient air quality through emission reductions. The program allows facilities to choose the most cost-effective technology or mechanism, and its implementation timing, to match emissions with the annual allocation, thus allowing greater permitting flexibility than seen in the traditional command and control (district specified emission control technologies or emission levels, or implementation schedule) programs.

2. System-wide emission rate or mass caps are similar to the RECLAIM market incentive program in that the caps allow the system operators to choose how to operate or modify the emission performance of the system while complying with the cap. The caps are adjusted down over time to achieve an improvement in ambient air quality through emission reductions. Over the period of time in which the cap is in effect, operating or modification decisions can be made in a more cost-effective manner compared to the traditional command and control (district specified emission control technologies or levels, or implementation schedule) programs. If, under restructuring, the systems are split into smaller systems, the caps will still achieve the same level of emission reductions and air quality benefits, but the sub-systems may not offer the same degree of operating or modification flexibility and cost-effectiveness expected under the caps implementation for the original system.

3. Offsets are typically required for larger facilities (the threshold levels change from air district to air district) at a ratio greater than 1:1. Therefore, new emission sources that are offset will produce a net (as high as 100 percent) emission reduction. Additionally, the offsets are based on the historical operation, not permit limits, of the emission reduction source. Since most air emission sources operate at less than permitted values, the conversion of historical emissions to offsets reduces the potential air emissions inventory.

4. Except for power plants located in Mexico.

Chapter 3

How Will Air Regulations and Emissions Respond to New Generation?

Permitting New Power Plants

About 30 new thermal power plants, all natural gas-fired combustion-turbine based, either have been proposed to the Commission for licensing or are expected to apply in the next few years (see **Figure 1** and Appendix A for a description of some). Other power plants not under Energy Commission jurisdiction are also being proposed in California.

California has an air regulatory infrastructure of local, state, and federal rules that is designed to permit new sources while making progress towards, or maintaining compliance with, air quality standards. The proposed projects will be among the cleanest in the nation, using natural gas and state-of-the-art technologies. Agencies will still need to review the project applications to ensure compliance with air regulations. The review has emission and process implications, including but not limited to:

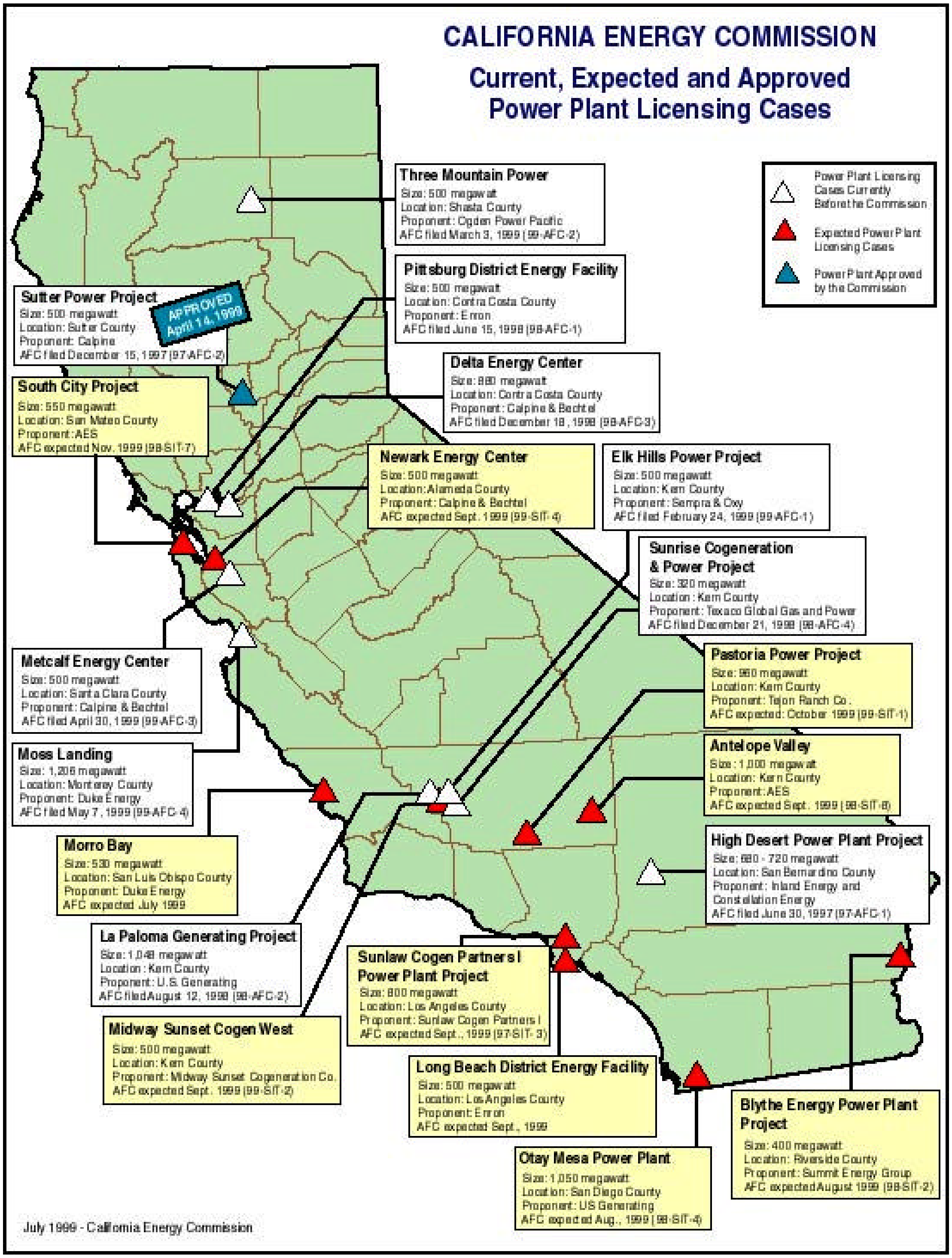
- Applicants, the public, and agencies are interested in timely review of the power plant applications.

- There is currently not a final consensus on BACT for large combustion turbines. The discussions regarding specific pollutants and averaging times are occurring in power plant licensing proceedings before the Energy Commission. The CARB's guidance document for large power plant permitting, expected this July, will provide specific guidance to districts on BACT requirements.

- The offset market will tighten and prices will become more volatile.

- The competitive market encourages more power plant cycling, and new power plant owners are proposing to operate with a large number of start-ups and shutdowns during which emission controls are less effective and emission rates may be higher than BACT levels measured during steady state operation.

Figure 1
Map of Current and Expected Siting Cases



Early consultation and agreement on these issues, which the Energy Commission staff will try to facilitate, is intended to avoid delays in the process and ensure consistency between local, state and federal permit requirements. Early consultation among the districts, the CARB and U.S. EPA can avoid delays by avoiding the need to revise the districts' Preliminary Determinations of Compliance with BACT and offsets requirements, etc. The CARB is actively developing a guidance document to districts for major power plant permitting. This guidance document, currently proposed for CARB approval in July 1999, should be available to assist districts in preparing the permits for most new power plants anticipated to proceed through the Energy Commission certification process. (The CARB briefing paper on the purpose and scope of the proposed Guidance Document for Major Power Plant Permits is included as Appendix D.)

Availability of Offsets

Even with BACT installed, many of the proposed new power plants will emit enough pollutants to exceed the New Source Review threshold triggers requiring emission offsets for NO_X, CO, PM_{10}, SO_X, and ROG. Emission offsets must be real, quantifiable, permanent, enforceable, surplus, and based on conservative operating scenarios. Because some air quality management districts in which new power plants are proposed have a scarcity of banked emission reduction credits to provide offsets, some projects may resort to unusual emission controls or offsets proposals, thereby complicating the licensing process and increasing the uncertainty of its results. Additionally, readily available emission offsets could be depleted in an air basin. Districts and local governments may experience other businesses and projects competing for those offsets. All developers likely will pay more for offsets and/or pursue alternative sources or emission control technologies. The CARB's guidance document will provide specific guidance on interpollutant and interbasin offsets as well as guidance on submitting complete offset proposals.

New Operational Profiles and Patterns

The power plants being proposed for construction will operate in a competitive market. Project proponents are requesting air quality permits that allow more frequent equipment start-ups and shut-downs so that the power plant will have the flexibility to generate when profitable and shut down when electricity prices are too low to make generation profitable. Emissions may be higher than with steady state operations from such plants due to frequent load transitions during which emission control systems can be less effective. The BACT determinations and offset requirements will need to take start-up and shutdown emissions into account.

New Out-of-State Generation

If new generation is constructed outside of California, it will likely be gas- or coal-fired. Those projects that emit greater than 100 tons per year of any pollutant would be subject to federal Prevention of Significant Deterioration (PSD) analysis, perhaps requiring offsets. The most significant components of a PSD analysis are the application of BACT, an air quality impact assessment, and the analysis of the project's impacts on Class I areas, including a visibility analysis. These analyses should ensure air quality does not deteriorate and act as incentives for the proposed projects to be designed with up-to-date technology and be located at sites with a consideration of their potential impacts on Class I areas. It is unlikely that emissions from generation outside of California will affect California emissions or air quality.

The Generation System Emission Effects Of Small or Nontraditional Generation Technologies

A district's attainment strategy can be affected by public purpose programs that support small distributed energy resources, research and development of emissions-related technology, and renewable generating sources. Emissions from small and renewable generation are part of the emissions inventory that air districts must manage as part of their attainment strategies. Electricity from non-emitting small and renewable generation may be relied on in attainment strategies to displace electricity from other emitting generation. To the extent that a district's strategies make express assumptions about the availability or operational profiles of small and renewable generation, these strategies could be affected if future industry conditions lead to changes in availability or operational profiles.

Small Cogeneration and Distributed Energy Resources

Small distributed energy resource (DER) units may become economically attractive in a restructured electricity industry and, in part, displace existing generation capacity. DER units may be installed to provide system voltage support or to defer transmission line construction. Some of these units, however, may not be large enough to trigger the minimum threshold of air district permit rules,[1] thereby avoiding BACT and offset requirements. Therefore, the widespread deployment of such generating units could create emission increases in California's air basins beyond those projected in district air quality management plans. Whether such increases are significant will depend on the location, number and mix of DER technologies added to the system (*e.g.,* whether fossil fuel-fired or non-fossil fueled such as photovoltaics or relatively clean fuel cells; whether a combined heat and power unit, which may reduce emissions from industrial processes). If significant emission increases occur, some air districts may need to modify permit requirements or planning assumptions to maintain or improve ambient air quality conditions. Equally, if a significant number of

relatively clean DER technologies are installed, then in-state generation air emissions could decrease. (See Appendix E for a description of distributed energy technologies.)
The Energy Commission led the creation of California Alliance for Distributed Energy Resources (CADER). The collaborative, kicked-off in October 1996, formed four working committees to address key issues and barriers to DER development and deployment. CADER held a conference in September 1997 and issued a collaborative report and action agenda in January 1998. The CADER and other national organizations have identified potential barriers to the broader application of DER.

- The CADER has identified specific studies that need to be undertaken to better understand the implications and impact of DER in the restructured environment.

- The Energy Commission, through its PIER funding mechanism, has approved several projects addressing strategic areas of distributed resources.

- In anticipation of an emerging DER market, responsible air quality management agencies are evaluating the potential air quality implications.

- The CARB initiated a contract study of the penetration of DER under various air regulatory scenarios.

- The Energy Commission is participating in a contract with DOE and U.S. EPA to evaluate DER and Combined Heat and Power technologies and market potential.

In December 1998 the CPUC issued an OIR on distributed generation and distribution competition. The OIR calls for a collaborative effort between the CPUC, Energy Commission, and Electricity Oversight Board (EOB) to develop a regulatory roadmap for addressing the technical and policy-related issues surrounding distributed generation and distribution competition. More than 60 parties filed opening comments in March 1999, and more than 40 parties filed reply comments in May. A full panel hearing was held on June 1, 1999, which enabled the CPUC and Energy Commission commissioners and EOB executive director to interact with panelists as they addressed the major issues surrounding distributed generation market development, distribution competition, the role of the utility distribution company (UDC), and recommended procedural next steps. The CPUC, Energy Commission, and EOB staff are collectively writing portions of the draft Proposed Decision, which they expect to be issued on August 16, 1999.

Public Interest Energy Research (PIER)

To date those PIER projects funded in the environmental subject area with some air quality implications are as follows:

- Regional Ambient Aerosol Study
- Desert & Mountain Transport Study
- Studies of Low NO_X Burners, Electro-technologies, and Pollutants from Food Preparation
- EPRI Global Climate Change Study
- Reducing Costs of Renewables

These research and development activities may provide a scientific basis for resolution of issues likely to surface during review of new power plant applications including, but not limited to, air pollutant transport, secondary air pollutant formation, offset proposals, and effectiveness of emission control technologies.

Public Purpose Funding of Renewables

The State Legislature determined that continued support of existing, new and emerging renewable generation technologies was important to the citizens of California at least during the transition to a fully competitive market. Electricity distribution companies are authorized to collect a public purpose charge from ratepayers during the transition period to provide subsidies to existing, new and emerging renewable generation technologies (see discussion in Appendix A).

It is possible that the Legislature may decide to continue this support at some level beyond the transition period. In addition, the retail electricity fuel type disclosure features of SB 1305 can help to facilitate product differentiation and encourage marketing of electricity based on renewable energy technologies.

Knowing how this support may change is important for air quality regulators and planners for three reasons. First, continued support may maintain existing or encourage new, albeit renewable, emission sources in air basins that may retire or not be built if it were not for the subsidy. To use biomass power plants as an example, the districts not only need to manage and plan for the emissions from the biomass plant itself, but also may need to manage and plan for the emissions from activities that could be affected by the future absence or change in operational profiles of these generation sources (i.e., open-field burning of the biomass fuel).

Second, continued support may maintain existing or encourage new non-emitting generation sources (e.g., wind or small hydro power plants) that may retire or not be built if it were not for the subsidy. In some cases, an air district may have included an express assumption about the effect that the availability of such non-emitting electricity supplies would have on the operations of pollutant-emitting generation within its district.

Third, continued support may allow operational profiles of supported generation to continue unchanged by shielding them from competitive pressures that could lead to increases in emissions beyond the amount expected. For example, geothermal power plants generally have to reduce their electricity production when electricity prices are very low. However, to maintain steam field production, geothermal steam is still produced and vented directly to the atmosphere, which can increase emissions associated with the geothermal operations.

Global Climate Change Emissions and Electric Industry Restructuring

The most significant non-criteria pollutant created by electricity generation is carbon dioxide (CO_2), which may contribute to global climate change. In 1992, the United Nations Framework Convention on Climate Change established a goal of stabilizing the net emissions of greenhouse gases in industrialized nations at the 1990 levels by the year 2000. The United States adopted this goal in the U.S. Climate Change Action Plan instituted in October 1993, which relies mainly on voluntary measures, including measures to be taken by electric utilities.

In 1997, United States representatives met with approximately 150 other nations in Kyoto, Japan, and committed to a greenhouse gas emissions reduction of seven percent below 1990 levels within the 2008 – 2012 timeframe. The Secretary of State's Office signed the agreement, the "Kyoto Protocol," on November 12, 1998. If the U.S. commitments in the agreement are ratified by the U.S. Senate and if federal or State requirements are placed on California, then sources of global climate change emissions, including electric generation, could be required to reduce their CO_2 emissions by an as-yet-undetermined amount.

Per the Energy Commission's *1997 Global Climate Change Report*, California's electricity generation sector currently accounts for a little over 16 percent of the CO_2 emissions produced in the State, compared to the national average of 39 percent. In-state CO_2 emissions will be reduced to the extent that electricity industry restructuring contributes to an increase in the fuel efficiency of carbon-emitting generation (i.e., by the replacement of existing generation with new, more efficient lower CO_2-emitting, combined cycle power plants) or to an introduction of new non-emitting generation sources or new demand side management opportunities.

Can More Efficient Ways Be Found to Reduce Generation Emissions?

Expanding the Use of Incentive-Based Programs

Siting activity associated with restructuring is putting pressure on the NSR emission reduction credit (ERC) market. With strong demand for credits, districts and facilities are exploring every avenue for meeting offset requirements. This strain is symptomatic of the

limitations of current emission trading programs; strategies that could help air districts achieve their air quality goals more cost-effectively without deterring economic growth are not yet fully taken advantage of. Changes made now, such as allowing more varied sources and uses of credits, could mitigate potential emission reduction credit shortages or price spikes that unnecessarily limit growth and avoid a return to thin markets in which sources have weak incentives to identify emissions reductions beyond regulatory requirements.
The NSR rule was established to allow growth while assuring a net air quality improvement, and it is effective for that purpose. While the NSR offset program is often described as an example of a market-based program, that was not its original intent. It was only with the addition of emission banking and area bubble policies that the program created economic incentives to reduce emissions. As a result, the program differs significantly from a fully efficient market for emission reductions for the following reasons:

- Rule requirements limit the supply of credits, resulting in higher prices than would be expected in a broader program that included more diverse sources. NO_X reductions from small combustion sources can cost as little as \$2,000 per ton, compared to NO_X ERC prices of \$5,000 per ton and up. To the extent that unregulated stationary sources are more cost-effective to control, we miss out on opportunities to encourage emission reductions that are difficult to achieve with source-specific rules. For example, the SCAQMD's Area Source Credit rule encourages new emission reductions credits by establishing a procedure for banking emissions reductions from area sources. Because area sources are unpermitted, the need to quantify emission reductions beyond regulatory requirements prevented these emissions from being included in the market.

- Because the program constrains the ways in which credits can be created it gives weak incentives to invest in emission reducing or avoiding strategies. An efficient credit market should impose an opportunity cost for every ton of pollutant emitted. The initial offset requirement for new sources is based on potential or "future expected," not actual, emissions. Once the plant is in operation, the original purchase is a sunk cost. While certain plant modifications and limitations can earn ERCs, other operational changes that could reduce emissions would not qualify for ERCs without the facility giving up flexibility. Uncertainty about discounting at the time of use also reduces the incentive to create ERCs. Whether or not the plant purchased offsets when built, the opportunity cost signal is limited.

- While this partial opportunity cost signal undermines the incentive for older plants to reduce emissions, new sources face much higher hurdles. In an efficient market the cost of a ton of emissions would be the same for all sources. To the extent that regulations add economically and environmentally inappropriate barriers that make it more difficult to build new facilities, which will tend to be cleaner and more efficient overall, we protect old plants from competition and delay the day when they are shutdown or rebuilt.

State and local air agencies have already made some changes to incorporate more incentive-based features and increase potential supply, for example by allowing the use of mobile source credits, and the SCAQMD Area Source Credit rule. While this trend is positive, more can be done to promote an active market that alerts emissions sources to the expected market value of their emissions and potential emission reductions. Like thinly traded unlisted stocks, emission reductions will be perceived as a much riskier investment when the market for credits is not robust. More buyers and sellers and more frequent trading would send a stronger opportunity cost signal, encouraging both old and new power plants to operate in an environmentally and economically efficient manner.

In addition to allowing credit creation from more emission source categories, extending the market spatially or across pollutants is another way to increase the number of participants and reduce costs. Where consistent with ozone transport patterns, sources can now trade across district lines. Price distortions associated with district borders and differences in the district source population can be minimized. Whereas in a thinly populated district prices might be unusually high, appropriate cross border trades can open up additional source of supply, equilibrating prices across districts. Interpollutant trades between NO_X and VOCs (volatile organic compounds), both of which contribute to ozone formation, also allow more trading. This allows facilities to locate where they are economically desirable, even though offsets may not be available locally.

Another strategy that can increase demand is the interchangeable emission reduction credit (IERC), in which credits created under the ERC, mobile source credit, alternative compliance, or other rules can be used interchangeably. The CARB Rule 1777 established a uniform methodology for the exchange of stationary, mobile, or area credits, but districts still need to develop their own rules before such trading can occur. IERC trading would allow a balancing of control costs across a much wider pool of sources, promoting compliance flexibility, cost-saving opportunities, and technological advancements. Even if a district decides to keep its IERC credits separate from ERCs, such a rule can benefit the offset market by increasing the number of potential buyers for those who create new emission reductions, encouraging them to participate in the market. Because each region has a unique situation, Rule 1777 provides a general framework within which air districts can expand the use of incentives in ways that meet their specific needs. The cost and benefits of alternative program details will depend on each district's source population, air quality conditions, expected growth, and other issues.

Greater use of interchangeable emission reduction credit and other incentive-based rules could potentially encourage more environmentally efficient operation of power plants and other facilities at lower cost, without interfering with air quality goals. Progress has been slow, however; developing and implementing these rules is a challenging, resource-intensive process for the districts. Some of the critical issues for developing and promoting their use include:

- The development and agreement on source-specific credit calculation protocols. Once protocols are established for a source category, suppliers of credits face a much-reduced regulatory burden. On the other hand, individual districts may not have the resources to develop the protocols, especially when they do not know which source categories are likely to attract attention first. A collaborative effort between air districts, CARB, interested emissions sources, and others could prioritize source categories, pursue needed resources, and share in the work required to develop protocols for use by all districts.

- Reducing the cost of the measurement and verification protocols for a wide universe of sources. For most sources in trading programs, continuous emissions monitoring (CEMS) is required to verify actual emissions. For smaller sources, the cost of CEMS would be a major obstacle. Low cost and easy to implement measurement and verification procedures for small and unpermitted sources would help bring into the market source categories that are difficult to regulate by traditional methods. If lower cost, less burdensome alternatives to CEMS such as sampling methodologies or fuel use records can be developed that are equally satisfactory at verifying emissions, the benefits of developing IERC rules would be greater for both districts and sources. The U.S.EPA-approved predictive emissions monitoring systems (PEMS) hold some promise for overcoming this hurdle for small emission sources, provided that they can be shown to quantify emission reductions with sufficient certainty to qualify them as credits. The CARB, districts and interested parties should develop a research strategy to address this issue, including the possibility of PIER-funded research.

- Interdistrict trading requires some regional consistency in banking, trading and attainment planning. The previously mentioned CARB guidance document to districts will provide guidance for interpollutant and interbasin offsets. It is also an opportunity to address consistency in attainment planning.

To the extent that these issues are resolved successfully, they can result in both environmental and economic benefits by motivating sources to identify and implement cost-effective emission reductions that regulators would find expensive or impossible to achieve through source-specific rules. Especially important for the future, they induce investment in new emission avoiding or reducing technologies.

Incentive Strategies for Reducing Electricity Generation Emissions

The prospect of increasing number of power plants in California sometimes raises suggestions for strategies focused specifically on generation emissions, such as a power plant emissions charge or an emissions trading market. Generation-only ‘internalization’ strategies may have made sense in the context of the pre-restructuring resource planning process, but as we move to competitive energy markets it becomes more important to evaluate incentive strategies with respect to how they will fit within the existing air quality standard attainment planning framework in California.

The concept of an emissions charge is the textbook economic solution to valuing emissions, but in practice in California it presents severe problems. In theory the appropriate charge would be for each unit of emissions from each plant, adjusted for marginal damages based on location and other physical characteristics. Even assuming we could agree on the methodology (which was never satisfactorily resolved in the old electricity resource planning process), the ideal charge would most likely conflict with district attainment plans. To set a charge aimed at consistency with air quality management plans, the emissions reductions or level required from the charge would have to be specified for each power plant in each district. If the charge is set too high, it results in unnecessarily high electricity prices; if too low, power plant emissions can exceed what was planned for. While emission market price forecasts have typically overestimated prices, the consequence of this is simply that program costs and socioeconomic impacts are overestimated. In the case of charges, the consequence of this overestimation would be selection of an initial charge that is too high, inflicting economic harm on participants and the economy that exceeds the environmental benefits.

Another generation-targeted approach might be an electricity generation emissions credit market. For example, a total NO_X cap could be defined, with air basin-specific constraints, and all plants could be required to hold credits equal to their emissions. New and existing plants would bear the same cost per ton of emissions, and firms would have an incentive to minimize emissions in all their plant operation decisions. A major concern for a generation-only market is the number of participants and degree of competition. If a new plant must locate within a particular emission trading zone to be competitive (i.e., close to a transmission line) and the only potential seller of credits is a competing power plant, a new entrant could be excluded even though the new plant is economically and environmentally efficient. Programs like NSR and the SCAQMD's RECLAIM, which include many source categories, dilute this ability to use emission credits to restrict competition.

Any strategy focused solely on electricity generation emissions is likely to create inconsistencies across sectors, where a ton of NO_X is treated differently in one industry than another. This approach could result in situations where competing businesses face different emissions costs because one's use of cogeneration leads it to be classified as generation and another is not. With the rise of distributed generation, this problem could become acute. It could result in distorted relative prices of electricity and other energy sources, and it would limit cost-saving opportunities. Emission reduction credit prices, and thus electricity prices, would be higher than in a broader market, because there are lower cost emission control options outside of the generation sector. However, such a generation trading program could be efficient if designed as part of a larger move towards more trading, for example including other major sources, offset ERCs, mobile sources, compliance credits, and area sources.

Any generation-only approach misses the opportunity to support the trend of air quality management programs, discussed in the previous section, that include a broader array of sources, resulting in lower costs, lower emissions, and most importantly, spurring emission-reducing innovation in all sectors of the economy.

Endnotes

1. The NSR program is a federally mandated program which applies to non-attainment pollutants. The PSD program is a federally mandated program that applies in areas that are in attainment of the national ambient air quality standards.

Chapter 4

Conclusions

Air quality regulators are responding within the existing framework to ensure that electricity industry restructuring will not, by itself, result in a deterioration of air quality from increases in emissions from electricity generation. Both existing and new electricity generation sources of air pollutants are subject to appropriate rules and regulations. The current attainment plans include rules and regulations that bring existing boilers down to emission levels that are some of the lowest in the country. BACT rules will make new generation cleaner yet, and their effective emission rates are much less than that of the existing boilers due to the fact that they are much more efficient than the existing fossil-fired steam boiler system.

The differences in operating profiles between existing and new electric generation emission sources will be taken into account both in permitting and in air quality management planning. Significant changes in generation patterns could potentially require a change in the attainment plan to ensure maintaining progress to attainment. Such a change in the plan may or may not occur in the generation sector. Some changes in generation patterns will be accommodated within existing programs, such as RECLAIM, for example. Regardless of the implications of restructuring on the operating patterns of most generators in the South Coast District, the RECLAIM program should result in no net change in NO_X emissions. If higher demand for RTCs results in higher RTC prices, some generation could shift to other air basins if the RTC costs are higher than other variable costs.

The Energy Commission has potential licensing proposals for as many as 30 large central station power plant projects that will be reviewed in the next two to four years. Most are subject to NSR requirements to install BACT and secure emission offsets to help local air districts attain and maintain ambient air quality standards. Recognizing the need for consistency in air quality permitting of these facilities, the CARB is already preparing a *Guidance Document for Major Power Plant Permits* to provide districts with specific guidance for emission control requirements and emission offsets, including interdistrict and interpollutant offsets.

Where offsets are scarce, new emission reduction incentive mechanisms should be developed to help maintain progress to attainment of air quality standards efficiently. The design of these mechanisms will need to take the new electricity market structure into account. If new emission offset and reduction incentive mechanisms are broadened to include emissions from the nongeneration sector, generation emissions may increase, but overall emissions would not. And the cost-effectiveness of controlling emissions would increase as investment flowed to the most productive emission control actions.

Restructuring and divestiture has created different economic incentives to run, retrofit, refurbish, repower, replace or retire existing power plants than in the regulated market. Such incentives could also result in different power plants being cost-effective to operate than was the case without restructuring. Consequently, geographic and temporal generation patterns may change, requiring air districts to revisit planning assumptions, expected source category emission reductions, and regulatory strategies (rule changes) needed to reach attainment. As discussed above, the districts have revised their BARCT rules to ensure that they still apply to the power plants, regardless of ownership. In some cases, owners may chose alternative technologies not envisioned when the BARCT rule was formulated. In other cases, owners may employ shutdowns, curtailments, and additional emissions controls to transfer emission reduction credits to other sources.

Air quality planners and managers need to understand and take into account the inherent uncertainty during and beyond the restructuring transition period about activities that affect their emissions inventories. These include activities such as the market penetration of distributed energy resources and their emission characteristics and the uncertainty about continued public purpose funding for renewable generation, demand-side management, and emissions-related research and development.

The Energy Commission, CARB, and affected air districts should continue their efforts to coordinate energy industry monitoring and air quality management. Regular meetings of Energy Commission and CARB with the California Air Pollution Control Officers Association Planning Managers and Engineering Managers proved beneficial in preparing all agencies to participate in the environmental review of divestiture. Continued coordination should benefit the CARB's efforts to develop their *Guidance Document for Major Power Plants*, future CARB or district rules changes, or future air quality management plan updates.

Appendix A - California Electricity Market Restructuring

The CPUC proposed restructuring of the California electricity market in December 1995. An environmental analysis was initiated on the effects of restructuring, but the EIR process was terminated when the State legislature passed Assembly Bill 1890 (AB 1890) in September 1996. Legislation is not subject to environmental review, but the CPUC did complete environmental reviews (discussed below) of the sales (divestiture) of utility fossil-fueled generation assets called for by the December 1995 CPUC decision.

AB 1890 mandated a competitive generation market, starting in January 1998 (the market restructuring was ultimately initiated in March 1998). AB 1890 applies for the most part to the investor-owned utilities in California subject to CPUC regulation. The legislation also created a Power Exchange (PX) and Independent System Operator (ISO). In the California restructured electricity market, the generation sector is transitioning to a competitive market. Generation is bought and sold through the PX or bilateral contracts, the terms of which may be linked to the PX price. CPUC-regulated utilities still provide distribution services, and the newly formed ISO provides transmission services to market participants. Municipal utilities and irrigation districts are not directly affected by the requirements of AB 1890, but they will be operating in an evolving, competitive electricity market.

As part of the AB 1890 implementation process, the State Legislature has passed some clean-up legislation in the form of SB 90 – Renewables and Public Interest Energy Research funding. SB 90 led to the creation of two programs at the Energy Commission that fund renewable energy and public interest energy research.

New Market Participants

Where once there were only three large investor owned utilities that owned the bulk of the generation in-state, divestiture has resulted in at least eight additional power plant owners and operators. These entities, while unfamiliar names to most Californians, are for the most part large and experienced companies in the generation of electricity. (Appendix B provides the names of the companies that have purchased existing utility generation to date.)

Existing Generation Resources

In-State Utility Power Plants – Divestiture

One of the first implementation issues that came out of the effort to restructure California's electricity market was divestiture, or the selling of utility generation assets. As the CPUC, and then the State Legislature, worked to define restructuring of the California electricity industry, it was recognized that there needed to be some limits on the market power of the existing investor owned utilities' generation resources. The CPUC recommended that Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E) divest at least 50 percent of their fossil generation capacity. It was expected that the divestiture process would be an open auction to determine the true market value of the assets and any adjustments to the Competition Transition Charge (CTC).

While divestiture was only a recommendation, the utilities have undertaken to sell almost all their generation capacity, including in-state fossil-fueled, geothermal, hydroelectric, and contract capacity. Divestiture has proceeded rapidly, with only a few fossil-generating units being withheld from sale.[1] Appendix B to this report shows the current status units being currently proposed for divestiture. Of the 18,450 MW that have been sold, 14,700 MW are "must run," those units that must operate to provide system ancillary or reliability services such as stability, voltage support, or spinning reserve. The must run contracts were determined by the Independent System Operator (ISO). Many of these units will probably retain their must run status until new plants start coming on line in the 2001/2002 time frame. Even then, certain plants, which provide local or system-wide ancillary services, may continue to operate at some capacity level.

Most of the units sold were large boilers with steam turbines. Included in the sales that have been completed were one combined cycle, some geothermal, and numerous combustion turbine peaker units. Almost all are more than 20 years old; most are more than 30 to 40 years old. Despite their age, some are candidates for modernization for reasons of their location and system value; they were well designed and well built and the asset still has some utility. Almost all are natural gas-fired, some are dual fuel capable, but current rules prohibit oil firing, except for testing or natural gas curtailment for most of the units.

To date, only SDG&E has proposed to sell their nuclear capacity, which is a 15 percent share of the San Onofre Nuclear Generating Station capacity. SCE and PG&E have not put their in-state nuclear generation (San Onofre and Diablo Canyon, respectively) on the market. SCE has not yet proposed to divest their hydroelectric system, their power purchase contracts, or their out-of-state power plants (a portion of one nuclear and several coal plants). PG&E is proposing to transfer their 3,910 MW hydroelectric system to their unregulated arm – U.S. Generating.

Nuclear Power Plant Closure?

The future of nuclear generation in California is uncertain beyond the transition period. Given that San Onofre and Diablo Canyon have a combined capacity of almost 4,300 MW, their retirement, due to competitive pressures, could have local and system-wide effects.

Out-Of-State Power Generation

California purchases and sells electricity through the Western U.S., Northwestern Mexico and Canada. How this market might change over the long-term with the restructuring of the California electricity market is uncertain. Out-of-state generation can effectively compete in the California market. Adequate transmission capacity is available during most time periods.

Many of the coal-fired generation units that are currently operating in the West were built at a time when very few air pollution regulatory programs were in existence. Some of these power plants are virtually uncontrolled, but through programs such as the Federal Clean Air Act Visibility Program and the Title IV Acid Rain Program, the emissions from these units' are gradually being controlled.

New California Electric Power Generation

Large Central Station Generation Projects

With the advent of restructuring in California, there has been remarkable interest in building and operating new electric generating power plants, of the 400 to 1000 MWe ranges, in the State. To date, the Energy Commission has approved one project, seven more are under Commission review, and 12 more have been publicly announced. All are proposing natural gas-fired combustion turbines with heat recovery steam generators for either steam production for process use or additional electricity production. The thermal efficiency in the proposed project's will exceed 50 percent (lower-heating value – LHV).

The Sutter Project was approved April 14, 1999 by the Energy Commission as a 500 MW combined cycle. Key features of the project include the following:

- 2.5 ppm NO_X at 15 percent O2, using dry low-NO_X combustors and selective catalytic reduction (SCR);

- a thermal efficiency of greater than 55 percent (LHV) under most ambient conditions; and

- a dry cooling tower and zero discharge facility, limiting water use and discharges to waterways.

Seven more projects totaling almost 4,500 MW are under Energy Commission review. All are combustion turbines with heat recovery steam generators. Key features of these projects include the following:

- 2.5 ppm NO_X at 15 percent O2, using dry low-NO_X combustors and selective catalytic reduction; and

- thermal efficiencies of greater than 55 percent (LHV) under most ambient conditions.

Twelve more projects have been publicly announced and have entered into some form of pre-filing meeting with the Energy Commission. This group of projects consists of the following:

- more than 7,000 MW of new capacity;

- combined cycle or combustion turbine projects with thermal efficiencies of greater than 55 percent (LHV) under most ambient conditions;

- The potential application of an emerging NO_X reduction technology, instead of SCR, to control NO_X emissions;

- a mix of new and existing sites; and

- potential filings with the Energy Commission in 1999.

The existing sites that have been announced include replacements of Morro Bay 1&2 with a 500 MW CTCC and Moss Landing 1-5 by a 1000 MW CTCC.

Nine others projects have engaged in pre-filing discussions with the Energy Commission. These potential projects may include:

- approximately 4,500 MW of new capacity;

- CTCC projects with thermal efficiencies of greater than 55 percent (LHV) under most ambient conditions;

- the potential application of emerging NO_X reduction technologies, instead of SCR.

- a mix of new and existing sites; and

- potential filings with the Energy Commission in 1999/2000 time frame.

Some of these examples of power plant efficiencies are for new electric generation only (disregarding cogeneration heat output). Output in MW is nominal; actual may be somewhat higher. Efficiencies are given in HHV (LHV).

- Crockett -- 240 MW 50.1 percent (55.6 percent)
- High Desert-- 3 x 7F-- 720 MW 48.8 percent (54.2 percent)
- 2 x 7G -- 678 MW 49.6 percent (55.1 percent)
- Sutter -- 500 MW 46.8 percent (52 percent)
- Pittsburg -- 500 MW 46.4 percent (51.5 percent)
- La Paloma -- 1,048 MW 50.4 percent (55.9 percent)

Small Cogeneration and Distributed Energy Resources

DER are an emerging generation and storage category that may see broader market penetration in a restructured world for a variety of reasons. DER technologies can be best described as those that:

- generate or store electricity,
- are located at or near a load center,
- may be grid-connected or isolated,
- are small (kW range to about 20 MW),
- are highly automated and reliable and can run unattended,
- are modular, mass produced, and
- have low capital requirements.

In addition, some DER systems generally have a greater value than power supplied by large central power facilities, including:

- Customer values: cogeneration for thermal need, reliability, and power quality (some customers need very “electrically clean” power, free from harmonics and momentary blips);

- Distribution system benefits: the ability to defer or forego transmission and distribution upgrades, contribute to meeting peak demand, and preventing “lumpy” transmission and distribution investments;

- Back-up or stand-by and emergency power; and

- Social or environmental value: although some distributed energy resources emit air pollutants; others can be clean and/or renewable such as wind, photolvotaic, or solar. For example, a Southern California Edison study found that photolvotaic can defer replacement of older 4-kV distribution lines in residential neighborhoods; avoids tearing up streets and saves T&D costs.

The ability to provide values to customers beyond grid power, and at low incremental capital costs, will ultimately be the drivers of the DER market. On an absolute scale, it is cheaper to finance one 1 MW facility than one 100 MW.

Energy Programs and Research

Renewables Program

SB 90 directed that collected revenues be used "to assist in-state operation and development of existing and new and emerging renewables resource technologies." These include biomass, solar thermal, photovoltaic, wind, geothermal, small hydropower of 30 megawatts or less, waste tire, digester gas, landfill gas, and municipal solid waste generation technologies. The program is designed to distribute approximately $540 million over the next four to nine years.

A generation subsidy, only paid for actual generation, not a construction or maintenance subsidy, allocates $160 million to new generation—wind, landfill gas, geothermal and $243 million to existing generation, including the Geysers, wind, and solar thermal. They have to be on-line in four years, but pay out can carry through nine years. To date, the program is preparing to provide a generation subsidy to 540 MW of new renewable generation and 3800 MW of existing renewables generation.

Fifty four million dollars is allocated to support the development of new and emerging technologies, including small wind, PV, fuel cell, and solar thermal. Once they are built and operating (grid connected), emerging renewable technologies can apply for monies to offset construction costs.

As part of the outreach and education aspects of the program, $5 million is designated to support customer education and $76 million to provide rebates to encourage customers to buy "green power."

Public Interest Energy Research

The CPUC suggested that the Legislature adopt a non-bypassable "public goods charge" on retail sales to fund public goods research, development, and demonstration and energy efficiency activities. Funding focuses on activities not provided by the competitive market that are in the broader public interest. The mission statement of the Public Interest Energy Research Program:

> is to conduct public interest energy research that seeks to improve the quality of life for California citizens by providing environmentally sound, safe, reliable and affordable energy services and products. Public Interest Energy Research includes the full range of research, development, and demonstration activities that will advance science or technology not adequately provided by competitive and regulated markets.

In the past, such public interest energy research was conducted by the investor-owned utilities. The research was for the public good and energy related and, therefore was ratebased by the utilities and the CPUC. In 1997, Senate Bill 90 was enacted into law, establishing certain administration and expenditure criteria for the PIER program. The current legislation required that the program portfolio include the five subject areas:

- Renewable energy technologies
- Environmentally preferred advanced generation
- Energy-related environmental enhancements
- Two sub-categories of end-use energy efficiency
- Strategic energy research

The program, approximately $62 million per year for four years, is now administered by the Energy Commission. It is possible that legislation will be proposed to continue PIER beyond the current four-year program. Funding for research in support of regulated utility functions (*e.g.*, distribution) properly remains part of regulated rates and is not collected as part of the public goods charge.

Endnotes

1. PG&E has retained the Humboldt and the Hunters Point fossil-fueled facilities. PG&E has also entered into an agreement with the City and County of San Francisco to work towards shutting down the Hunters Point facility as early as possible.

Appendix B - Utility Power Plant Divestiture

Utility	Purchaser	Unit Name (a)	Must Run	Units	MW (b)	County	Fuel(c)
PG&E	**Duke Energy**	**Total**		**9**	**2645**		
		Morro Bay		4	1002	San Luis Obispo	Natural gas
		Moss Landing	Yes	2	1478	Monterey	Natural gas
		Oakland	Yes	3	165	Alameda	Distillate fuel
	Southern Energy Co.	**Total**		**13**	**3066**		
		Contra Costa	Yes	2	680	Contra Costa	Natural gas
		Pittsburg	Yes	7	2022	Contra Costa	Natural gas
		Potrero	Yes	4	364	San Francisco	Nat. gas/dist.
	Calpine	Geysers	Yes	**14**	**1224**	Lake/Sonoma	Geothermal
	Sale/transfer	Hydroelectric	?	Var	3,910	Various	Hydro
	Being held by PG&E	Humboldt	Yes	2	105	Humboldt	Natural gas
		Hunters Points	Yes	4	429	San Francisco	Natural gas
SCE	**AES Corp**	**Total**		**14**	**3,956**		
		Alamitos	Yes	7	2083	Los Angeles	Natural gas
		Huntington Beach	Yes	3	563	Orange	Natural gas
		Redondo Beach	Yes	4	1310	Los Angeles	Natural gas
	Reliant Energy (new name for Houston Ind.)	**Total**		**15**	**3,776**		
		Coolwater		4	628	San Bernardino	Natural gas
		Ellwood		1	48	Santa Barbara	Natural gas
		Etiwanda	Yes	5	1030	San Bernardino	Natural gas
		Mandalay	Yes	3	570	Ventura	Natural gas
		Ormond Beach		2	1500	Ventura	Natural gas
	Dynegy / NRG Energy	**Total**		**13**	**1,520**		
		El Segundo	Yes	4	1020	Los Angeles	Natural gas
		Long Beach		9	500	Los Angeles	Natural gas
	Thermo Ecotek	**Total**		**6**	**280**		
		Highgrove		4	154	San Bernardino	Natural gas
		San Bernardino		2	126	San Bernardino	Natural gas
SDG&E	**Dynegy / NRG Energy**	Total		**23**	**1269**		
		17 CTs <20 MW	Yes	17	302	San Diego	Nat gas & dist
		Encina	Yes	6	967	San Diego	Natural gas
	Up For Sale	Power Contracts	?	Var	175	out-of-state	Various
	Up For Sale	QF Contracts	?	Var	207	San Diego	Various
	Up For Sale	SONGS (20%)	Yes	20%	430	San Diego	Nuclear
	Port District	**South Bay**	Yes	**5**	**710**	San Diego	Natural gas
					18,446		

Notes to Appendix B – Utility Power Plant Divestiture

a. Units reflect the closures of Moss Landing 1-5. Units reflect the closures of Contra Costa 1-5. Units 4 and 5 condensers see some duty still. Geysers 1-4 have been closed. Huntington Beach 3 and 4 are inactive. Redondo Beach Units 1-4 are in long-term return to service. All these units have relinquished their permits to operate.

b. SCE MW show "summer maximum."

c. Some of the boilers were dual fuel capable; however, permit requirements generally limit operation with residual fuel oil to testing and emergency natural gas curtailments.

Appendix C - The Five R's - Air Emission Implications Of Run, Retrofit, Repower, Replace Or Retire

Where emission permit conditions are based on an emission rate rather than an emission mass cap, planning emission inventories typically include an assumption about how much the power plant will be run. If the power plant runs more than expected (that is, more than it was assumed to run in the planning inventories), then it can be said that its emissions have increased compared to what was counted on in the attainment plan. Potentially, a change in the attainment plan could be needed to ensure maintaining progress to attainment when updating the air quality management plans. If necessary, the change may or may not occur in the generation sector.

Running Existing Facilities: Owners of existing power plants may chose to run an existing facility under the same operational constraints[1] that were in place before restructuring. Alternatively, an owner could chose to modify the operations of the facility. In either case, the facility will be subject to the existing permit limits, including operational and chronological requirements for the implementation of BARCT rules (if they are revised to apply to any owner) and attainment strategies.

Retrofit and Refurbishment: Retrofits are often done as a consequence of BARCT requirements; thus, a retrofit facility may emit air pollutants at a lower rate. Refurbishment is done to improve the fuel efficiency or reliability of a unit, which can also reduce the emission rate (*i.e.,* mass emissions per power out). Retrofit and refurbishment may cause the power plant to be dispatched more often, as the owner attempts to recover the costs of the improvements or to take advantage of the improved performance. However, while emission rates may improve, total emissions from the facility may increase or decrease, depending on the new dispatch of the unit.

Repower: A repowering modernizes an existing facility, it will generally trigger BACT, BARCT, emission reduction credit (ERC), and/or offset requirements in most cases. Thus, a repower could reduce emissions two ways: by increasing on-site capacity and displacing existing older facilities with a new BACT-level generation source, and by eliminating the old facility that was repowered. Any emission reductions realized from the existing facility would be subject to emission reduction credit rules.

Replacement: Replacing an existing facility with a new facility may result in a decrease of system emissions as most new facilities will be subject to BACT and offset requirements.[2] Any emission reductions realized from the existing, "replaced", facility would be subject to ERC rules. Thus the emission inventory is reduced further by allowing only historical, not permitted, emissions to be credited and by using the banked emission reduction credits at a ratio greater than 1:1.

Retirement: The retirement of some of the State's large power plants could delay the retirement of other existing power plants because their generation may be more economic than otherwise. (The addition of new power plants would counter this effect, though). If the facility is fossil fuel-fired, the air emission reductions from its retirement may not be realized as expected. Air districts may have to revisit the retrofit rules and their planning assumptions regarding changes in expected retirements.

Endnotes

1. Power plants are operated under a variety of constraints. These include, but are not limited to, generation to meet load demand, power, voltage support, black start capabilities, system and transmission line reliability, and contingency planning. These types of constraints can cause a power plant to be dispatched irrespective of its true economic dispatch.

2. The replacement of a generation source (even an "emissionless" source like a nuclear or hydroelectric facility) with a new fossil-fueled power plant with emissions may result in an increase in emissions in the generation category; however, the replacement results in **net** reductions to the emission inventories in an air basin through the use of ERCs and offsets, at a ratio greater than 1:1, from various source categories. The reduction in emissions from a replacement is different than a power plant retirement, where the generation could shift to existing facilities without contemporaneous emission reductions (ERCs or offsets).

Appendix D - Air Resources Board Purpose And Scope Of Proposed Guidance Document For Major Power Plant Permits

BRIEFING PAPER: PURPOSE AND SCOPE OF THE AIR RESOURCES BOARD'S (ARB'S PROPOSED GUIDANCE DOCUMENT FOR MAJOR POWER PLANT PERMITS
(source: ARB Web Site, www.arb.ca.gov/powerpl/powerpl.htm)

This briefing paper uses a question-and answer format to discuss the purpose and scope of the ARB's proposed guidance document for major power plant permits.

1. What is the purpose of the guidance document?

The purpose is to set forth the ARB's existing guidance perspective for major power plant permits and provide specific guidance for emission control requirements (best available control technology) and emission offsets. ARB's guidance is designed to ensure that California will meet its clean air objectives by siting only the cleanest power plants in the State. The guidance document is intended to assist local air pollution control districts and air quality management districts (districts) in making permitting decisions as the districts participate in the California Energy Commission's power plant siting process. The document will address the following five areas: best available control technology (BACT) as defined in district New Source Review (NSR) permit program regulations, emission offsets, ambient air quality impact analysis, health risk assessment, and permit content.

2. How will the guidance document be developed?

Consistent with the CARB's oversight responsibility for air pollution control programs in California, ARB staff is drafting the guidance document and will provide it to interested parties for review and comment prior to the CARB's public hearing in July 1999. On February 24, 1999, CARB staff held a scoping meeting to discuss the BACT component of the proposed guidance document; invitees included district staff, CEC staff, electric utilities and equipment manufacturers. CARB staff is also holding public workshops on May 21 and 25, 1999, to discuss the scope of the document and to solicit input from interested parties.

3. How has deregulation of the electric utility industry in California affected power plant construction?

Over the next few years, the open market created by the deregulation of the electric utility industry is expected to result in an increase in new power plant construction with over 12,000 megawatts (MW) in generating capacity (based on 29 current and anticipated projects known to the CEC). The majority of the projects have individual capacities in the range of 500 to 1,000 MW. The proposed projects will produce electricity with large stationary combustion turbines using natural gas as fuel and equipped with state-of-the-art air pollution control technologies.

4. How will the new power plants differ from plants built before the deregulation of the electric utilities industry?

The new power plants will operate in the competitive market with more frequent equipment start-ups and shutdowns and more varied power loads; such power plants and operation are commonly referred to as "merchant plants" and "merchant operation mode," respectively. The additional equipment start-ups and shutdowns will increase emissions from these plants.

5. What are the expected air pollution impacts from the new power plants?

The operation of large stationary combustion turbines with natural gas fuel and state-of-the-art controls is expected to result in some of the lowest emission concentrations achieved to date for this source category. However, despite the benefit of lower emission concentrations, the combination of the merchant operation mode and the large size of the combustion turbines is expected to result in high emission rates. The high emission rates are likely to exceed district NSR program thresholds for emission offsets for oxides of nitrogen (NO_X) and carbon monoxide (CO). The largest projects may also exceed the offset thresholds for particulate matter (PM10), oxides of sulfur (SO_X), and reactive organic gases (ROG). The high emission rates may negatively impact ambient air quality and pose health risks.

6. What guidance will ARB provide regarding best available control technology (BACT)?

A generalized procedure for determining BACT and a technical review of recent BACT determinations for power plant combustion turbines will be provided in the guidance document. The generalized procedure will step through the major elements of district BACT definitions, including the "class or category of source," the "most stringent emission control contained in any approved State Implementation Plan," the "most effective control achieved in practice," and "any more stringent emission control technique found by the district to be both technologically feasible and cost effective." After review of performance data received to date for emission controls on combustion turbines, ARB staff believes that the following emission levels can be achieved:

- NO_X emission levels of 2.5 ppmvd at 15 percent oxygen using 1-hour averaging periods,
- CO emission levels of no more than 4 ppmvd at 15 percent oxygen,
- ROG emission levels of 1 ppmvd at 15 percent oxygen using 1-hour averaging periods,

- lowest SO_X emission levels from combustion of natural gas containing no more than one grain of total sulfur per one hundred standard cubic feet and delivered by an entity regulated by the Public Utilities Commission (PUC), and
- lowest PM10 emission levels from combustion of natural gas containing no more than one grain of total sulfur per one hundred standard cubic feet and delivered by an entity regulated by the PUC.

ARB staff is soliciting additional information to confirm, or to refine lower or higher, the preliminary emission levels listed above.

7. What guidance will ARB provide regarding emission offsets?

An overall guidance perspective for emission offsets, consistent with ARB staff review of recent power plant projects, and specific guidance for interpollutant and interbasin offsets will be provided in the guidance document. Overall, emissions offsets must be real, quantifiable, permanent, enforceable and surplus and based on worst-case operating scenarios. A complete offset package must be identified and quantified at the submission of the application, letters of intent signed by the time of the preliminary decision, and offsets secured and in place prior to operation of the power plant. Interpollutant and interbasin offsets may be allowed if there is an emission transport relationship and an overwhelming impact on the district accepting the offsets; the applicant must first exhaust banked and potential emission reductions onsite. ARB staff intends to develop interpollutant offset ratios by air basin, but does not preclude the case-by-case determination of appropriate offset ratios. ARB staff is proposing that interbasin offset ratios begin at a minimum of 2:1 and increase by one with each additional 25 miles distance beyond 50 miles. Interbasin offset transactions require the approval of both districts.

8. What guidance will ARB provide regarding ambient air quality impact analysis?

A brief review of the purpose and tools for performing ambient air quality analysis will be provided in the guidance document. A primary concern in siting a large power plant project is its impact on air quality. Does the project have the potential to prevent or interfere with the attainment or maintenance of any applicable air quality standard? Does the project have the potential to cause a significant degradation of air quality in an attainment area? Air dispersion models are the primary tool for relating emissions to air quality impacts. ARB staff will briefly describe established air dispersion models, procedures, and data criteria. Models used should be appropriate for the pollutants, operating scenarios, and relevant regulatory requirements such as averaging times of the air quality standards. Some models may be used for relating emissions to potential health impacts associated with a project. Prior to performing an air quality impact analysis, ARB staff strongly recommends that an applicant prepare a modeling protocol and provide it for review and comment to appropriate regulatory agencies, including the district and the ARB. Evaluation of air quality impacts should be conducted with models approved by the ARB and the United States Environmental Protection Agency.

9. What guidance will ARB provide regarding health risk assessment?

Districts have typically required applicants for large power plant projects to prepare and submit health risk assessments. A brief description of the purpose for a health risk assessment will be provided in the guidance document. A health risk assessment is an evaluation of the potential for adverse health effects that can result from exposure to emissions of toxic substances. ARB staff suggests that health risk be assessed according to guidance established by the Office of Environmental Health Hazard Assessment (OEHHA). The information provided by health risk assessment is considered in the district's risk management decision to decide whether or not a project should proceed.

10. What guidance will ARB provide regarding permit content?

Typically, the permit issued to an applicant will contain conditions to ensure that the construction and operation of a power plant will comply with all applicable air pollution control requirements. ARB staff will identify specific issues relating to the new power plants that should be addressed by enforceable permit conditions. The guidance document will address the following areas: emission limits, start-up and shutdown of the combustion turbines, compliance monitoring and source testing, fuel sulfur content, and ammonia slip (when NO_X is controlled with selective catalytic reduction).

Appendix E - Distributed Energy Resources Technologies

Commercial and Emerging

- Phosphoric Acid Fuel Cells (PAFC): 200 kW system PC 25 available from ONSI Corporation since 1991. In use at about 100 sites worldwide. Ninety-six percent reliability, with a mean time between forced outages of 2500 hours. Inherently modular by connecting stacks in series.

- Wind: Less than 50 kW to 1 MW. Intermittent technology, which results in low capacity factors. Susceptible to storm damage. Installed wind generation costs have decreased dramatically since the 1980s.

- Photovoltaics: 10 kW to 10 MW. Intermittent, but follows California's summer peaks well. Inherently modularity connecting multiple modules. Lots of potential for cost decreases. A 10 MW plant would require about 100 acres of land.

- Diesel and natural gas-fired reciprocating engines: 50 kW to 5 MW. Standard back-up technology of choice. Proven performance, low installed costs, efficient. Historically high NO_X, CO and particulate emissions (the latter are listed by CARB as toxic contaminants). Staged ignition, lean-burn, and SCR technology can help lower NO_X emissions. Cogeneration packages are readily available.

- Small gas turbines: 500 kW to 20 MW and larger. Lots of proven models and manufacturers. Available in generation, cogeneration and/or combined cycle configurations.

- Demand-Side Management: Must be targeted to the local area for maximum benefit. Includes customer energy efficiency (insulation, efficient lighting and appliances, shade trees) and load management techniques such as air conditioner cycling.

Technologies Being Demonstrated

- Batteries: 100 kW to 20 MW storage devices. Projected commercial date of 1997-2000. Inherently modular. Charged during off-peak periods with cheap electricity. Enhances reliability and power quality, and provides spinning reserve, and frequency regulation. Only the lead-acid type is available commercially. Recycling industry needs to be developed.

- Flywheels: 10 kW to 3 MW storage devices. Projected commercial date of 1997 to 2000. Inherently modular. Good for improving frequency control, stability, improving power quality, and high-power, short-discharge applications.

- Solar Dish Stirling: 5 to 50 kW per dish. Projected commercial date of 1999. Parabolic dish concentrates the heat, which is used to run a Stirling heat engine. Natural gas or even biogas or landfill digester gas can also be used to run the heat engine, thereby allowing continuous operation.

- Molten Carbonate Fuel Cells: 250 kW to 3 MW. Projected commercial date of 2000 to 2003. Operate at higher temperature than PAFCs, therefore can suit a wider range of cogeneration applications.

- Micro-turbines: 25 kW to 250 kW. Projected commercial date of 1997 to 1999. While low efficiency of 21 percent to 30 percent (LHV) compared to fuel cells, reciprocating engines, and MW-scale gas turbines at 40 percent, they are attracting a lot of attention. Capstone Turbines has a 30 kW product and AlliedSignal has a 75 kW product. They use a single shaft, few moving parts, and rotate at 96,000 rpm. They can use flare gases and biogas.

Technologies Being Developed

- Advanced Turbine System Small Gas Turbines
- Solid Oxide Fuel Cells
- Proton Exchange Membrane Fuel Cells

Appendix F - Specific Comments On The Report From Parties

Interested parties, including the Air Resources Board and local air district boards, have been given the opportunity to provide a letter commenting on the report to be included in Appendix F. None has been received to date. By July 28, 1999 an addendum to Appendix F will transmit comment letters received.